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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Approval of Demand Response Programs, Pilots and Budgets for Program Years 2018-2022.	Application 17-01-012
And Related Matters.	Application 17-01-018 Application 17-01-019

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) RESPONSE TO ADMINISTRATIVE LAW JUDGES' RULING REQUESTING RESPONSES TO QUESTIONS

ANNA VALDBERG
ROBIN Z. MEIDHOF

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-6054
E-mail: Robin.Meidhof@sce.com

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Pursuant to Administrative Law Judge (ALJ) Hymes' and ALJ Atamturk's Ruling Requesting Responses to Questions (Ruling), dated June 15, 2018, as well as ALJ Hymes' email ruling dated June 22, 2018, Southern California Edison Company (SCE) respectfully submits the following responses. The Ruling directed parties to A.17-01-012 *et al.* to respond to questions contained in the Ruling on several topics related to demand response (DR) by July 13, 2018 and to provide replies to the responses by July 27, 2018. ALJ Hymes' email ruling granted parties an extension until July 20, 2018 to file opening responses, and until August 3, 2018 to file reply responses.

The Ruling presents four sets of questions on the following topics: (1) a straw proposal on targeting demand response (DR) in disadvantaged communities (DAC) (Straw Proposal); (2) demand response dual participation rules; (3) implementation of the automated demand response

(Auto DR) incentive policy; (4) managing and/or modifying the two percent cap on reliability DR. The Ruling includes as attachments the Straw Proposal, a matrix of Auto DR technology incentive programs, a description of how the investor-owned utilities (IOUs)[1] allocate Auto DR costs across DR programs, and the IOUs' responses to a data request regarding storage controls and Auto DR incentive applications.

SCE respectfully provides its responses to the questions asked in the Ruling.

I.

DISCUSSION

A. Questions on the Straw Proposal for Demand Response Pilot Plans to Benefit Disadvantaged Communities

SCE provides its responses to the Ruling's questions regarding a DR pilot to benefit DACs below. SCE proposes that its pilot consist of three tracks to address three key concerns: (1) Collect information on the awareness, ability and willingness of customers located in DACs to participate in DR; (2) Conduct a pilot that seeks to electrify hot water heaters for residential customers located in DACs to provide immediate GHG reduction and enable DR participation; and (3) explore the feasibility of revising SCE's DR tariffs to call events during times that gas-fired peaker plants are running.

As an overview, SCE manages a mature DR portfolio and has effectively marketed its DR programs to mitigate issues arising from the closure of San Onofre Nuclear Generating Station and the temporary closure of the Aliso Canyon Storage Facility, among other targeted marketing. SCE has strong participation in its DR programs among residential customers located in DACs, with participation rates proportional to the overall SCE service territory. SCE promotes its residential programs to all eligible customers who would be good candidates for participation, regardless of whether they are located in a DAC or not.

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1 The IOUs are SCE, Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E).

In November 2017, SCE released the "The Clean Power and Electrification Pathway" (Pathway), a whitepaper that lays out a clear, cost effective path to reducing California's GHG emissions and improving air quality. By 2030, the Pathway calls for an electric grid supplied by 80 percent carbon-free energy, more than 7 million electric vehicles on California roads, and nearly one-third of buildings using electricity to power their space and water heating.[2] Today, space and water heating accounts for more than two-thirds of the GHG emissions from residential and commercial buildings.[3] Using highly efficient, electric-powered options for space and water heating in nearly a third of California buildings will reduce GHG emissions by 12 million metric tons across the state by 2030. One of the key considerations in pursuing the vision of the Pathway is that electric appliances installed today get "greener" over time as the proportion of carbon-free electricity will exceed 50% by 2030 pursuant to current state policies. This could increase even further if aligned with SCE's Pathway, which calls for 80% carbon-free energy by 2050.

The Straw Proposal provides an opportunity to align the Pathway vision with a pilot to explore how DR can be used to provide both economic and environmental benefits to customers located in DACs. For this reason, SCE proposes to undertake replacement of existing water heaters with electric water heaters as part of its pilot. Focusing on electric water heaters that can be used for DR will support GHG emission reductions and will be effective in improving the overall air quality in the long term, thereby providing sustainable and meaningful benefits for those living and working in DACs.

1. Comment on the merits of the Proposal, explaining your rationale.

The Straw Proposal is reasonable and appropriate to identify innovative and alternative ways to support our customers who are located in DACs with DR offerings that also support statewide emission reduction objectives. SCE will explore activities in its pilot proposal that

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[2] The Pathway is available at https://www.edison.com/content/dam/eix/documents/our-perspective/g17-pathway-to-2030-white-paper.pdf

[3] *See* Pathway, p. 8.

achieve long term GHG reduction coupled with bill management opportunities for customers through DR programs.

2. What changes or clarifications, if any, would you recommend and why?

Efforts that advance California GHG abatement targets should be prioritized. By prioritizing efforts that reduce overall GHG emissions, any activities performed as part of this DR DAC Pilot will have a long lasting and a significant impact to customers located in DACs.

3. Do you agree or disagree with the proposed definition of disadvantaged communities? Explain your reasoning.

The definition of a DAC presented in the Straw Proposal is consistent with the definition adopted in the Integrated Resource Planning proceeding. SCE supports using a consistent definition across the various proceedings and activities used to support DACs. However, there are challenges associated with implementing solutions using this definition. For instance, targeting customers for participation in programs and services who reside in the same zip code as a DAC area can cause difficulties when one zip code has communities identified as a DAC community and a non-DAC community. Because SCE identifies customer location by zip code, while DACs are identified by more-granular census tract, it is difficult to be sure which customers are actually located in DACs. Additional challenges with the definition could arise if communities move into or out of the DAC designation during the pilot period.

4. Comment on the adequacy of proposed requirements for disadvantaged communities demand response pilot plans listed under Section II of the Proposal.

The proposed requirements as discussed in the Straw Proposal seem to be appropriate. Commission policy exempts pilots from meeting cost-effectiveness thresholds,[4] and interprets requirement 5b as pertaining to measuring the cost-effectiveness of any program based on the pilot that would ultimately be implemented, not to the pilot itself. SCE also notes that care should be taken with requirement 5 (EM&V) generally, to avoid an overly strict requirement. For instance, requirement 5a appears to require a DAC pilot to consist of a test and control

[4] 2016 Demand Response Cost-Effective Protocols, p. 18.

group. However, this may not be appropriate for all pilot designs, and the IOU should have the flexibility to propose its preferred pilot design and an appropriate EM&V plan for that pilot.

5. Do you agree or disagree with the purpose and goal of disadvantaged communities demand response pilots stated in the Proposal? Explain your reasoning.

SCE agrees that customers located in DACs should have access to and benefit from California's clean energy programs. Testing clean energy appliances such as electric water heaters within DAC communities is one way to pursue this purpose and provide both economic and environmental benefits to customers located in DACs. SCE supports the Straw Proposal's clarification that the goal of the DAC pilots is to lead to the identification of policy recommendations to improve existing programs or contribute to the development of new programs, as opposed to immediately showing measureable environmental and economic impacts. This is a forward-looking goal that seeks to apply the findings of the DAC pilot as widely as possible, and not focus narrowly on the quantitative results of the pilot itself.

6. Do you agree or disagree with "adopting the method and initial set of candidate locations within each utility service territory proposed by Olivine, as the starting point for selecting pilot locations"? Explain your reasoning.

SCE has no concerns with the proposal to focus on certain communities within SCE's service territory, or with Olivine's methodology for identifying candidate locations. The communities identified by Olivine in SCE's service territory are San Bernardino, Colton, and La Puente. These communities are relatively populous and relatively close to each other, and performing the pilot in these communities could provide benefits, including reduction in implementation costs and increased likelihood of participation in the selected areas. However, SCE has also undertaken efforts to assist other DAC communities, including in the San Joaquin Valley. Aligning this DR pilot with those efforts may also yield some of the same benefits as performing the pilot in the communities identified by Olivine. It is important to take advantage of efficiencies that can make the most of the limited budget authorized for this pilot. SCE is working on identifying which communities are the most appropriate for its particular pilot, and recommends that it be given the flexibility to select the best communities, regardless of whether these are the communities identified by Olivine or not.

7. The Proposal notes, "Pilot objectives should . . . focus on identifying a few test objectives in order to maximize both the quantitative value of the results . . . and qualitative value of results to inform policy recommendations." What key objective do you recommend testing, with which strategy and customer segment, and why? (e.g. objective of increasing enrollment and participation of residential customers in DACs, through a community based outreach program strategy.)

SCE recommends three actions for its pilot. First, SCE recommends studying the barriers that may exist for adoption of DR by customers located in DACs through a comprehensive market study. Currently, SCE does not have much data regarding the ability, willingness, and awareness of customers located in DACs to participate in DR programs. SCE will conduct a survey to gather information related to these topics, and will look to leverage best practices to overcome barriers identified in the California Energy Commission's SB 350 Low-Income Barriers Study. In order to drive increased adoption of DR in DACs, we must first understand what barriers to increased adoption exist. The findings will inform future SCE efforts to increase awareness of DR options among customers located in DACs, and will help SCE implement strategies to increase enrollment. This effort will focus on both residential and commercial customers.

Second, SCE recommends launching a limited fuel substitution pilot that replaces heat pump water heaters (HPWH) powered by fossil fuels with electric water heaters. A DR component will be included that tests the DR responsiveness of these technologies and their potential load impact. Methods will include a study of the changes in total customer energy bills, test adoption and barriers to electrification of HPWH, and an analysis of the overall costs of fuel substitution to identify and properly incentivize fuel substitution or develop future on-bill financing options. The target population will be residential customers, including customers that may not have central air conditioning, which is currently the primary avenue for residential participation in DR. In cases where EE opportunities are available, SCE will explore leveraging existing offerings to benefit customer bill management such as smart thermostats, weatherization or other offerings as available.

Third, SCE recommends reviewing and evaluating existing DR program event triggers to see if modifications can be made to align and mitigate peaker plant dispatch. All customer segments and all programs should be reviewed and evaluated. This is a no-cost option and any identified solutions would only require tariff changes.

B. Questions on Dual Participation

SCE provides its responses to the Ruling's questions regarding dual participation below. To better organize its responses, SCE has split some questions into sub-parts.

1. (For third-party providers only)

N/A

2. Provide the statistics from the past three years regarding the number of customers you dis-enrolled from the Critical Peak Pricing program because the customers had been registered in a third-party demand response provider program.

The table below presents the numbers and percentages of SCE customers dis-enrolled from Critical Peak Pricing (CPP) due to the customer being registered in a third-party DR provider (DRP) program. This data covers the last three years and is current as of July 6, 2018.

	Total	Percentage
Total Non-Utility DRP approved registrations under Rule 24	40,517	N/A
Service Accounts (SA) dis-enrolled from CPP 90-days prior to enrolling in a Non-Utility DRP program	5	0.001%
SAs automatically dis-enrolled from CPP after Non-Utility DRP successfully registered the SA with the California Independent System Operator (CAISO)	13	0.003%

3a. (For SCE only) Explain your approach to capping incentives for dually participating customers. Do you use any other method to avoid double payments?

SCE's dual participation capping methodology was adopted in its 2009 Rate Design Window (RDW) Application (A.09-12-024) through Decision (D.)10-06-037. In its 2009 RDW Application, SCE proposed three rate design treatments corresponding to three unique DR program structures when customers participate in both capacity and energy programs. Below is a summary of SCE's 2009 RDW testimony. The complete testimony is attached to this response as Attachment A.

SCE's DR energy programs, which are called on a day-ahead basis, provide credits to customers through three basic structures:

- The first structure provides credits in each summer month regardless of whether a triggering event is called. Rates are designed so that the total value of the monthly credit is offset or balanced by an increased energy charge which only applies to usage during a called event period. The CPP program is one example of this type of structure.
- The second structure provides credits on a per event basis applied to the kWh reduction during the event, with no offsetting increased charge. An example of this type of program was DBP, now retired.
- The third structure provides benefits to customers who can avoid usage during certain high-cost hours where generation costs are concentrated. These benefits are essentially embedded in rates and reflected as lower hourly generation charges during the low-cost periods. An example of this type of rate structure is Real Time Pricing (RTP).

SCE incorporates three rate design treatments corresponding to these three structures when customers participate in both capacity and energy programs, as shown below.

Table 1
Energy and Capacity Based Programs Dual Enrollment Relationships

	Energy Program	Capacity Program	Treatment Rule
Structure (1)	➢Per event charge ➢Day-ahead trigger ➢Monthly credit **(example: CPP)**	➢Monthly Credit ➢Day-of trigger **(example: BIP)**	Cap summed credits to value of capacity reflected in the otherwise applicable tariff rate
Structure (2)	➢Per event credit ➢Day-ahead trigger **(example: DBP)**	➢Monthly Credit ➢Day-of trigger **(example: BIP)**	Eliminate energy program credit for concurrent events
Structure (3)	➢Embedded credit ➢Day-ahead trigger **(example: RTP-2)**	➢Monthly Credit ➢Day-of trigger **(example: BIP)**	Temporarily continue current practice of allowing dual enrollment without caps

The need for separate treatments is driven by the different energy programs structures. A single capping structure would satisfy the requirements for Structure (1) type programs, however the single structure was not considered compliant with California Public Utilities Commission (Commission) guidelines regarding programs that fall under Structure (2) where only capacity-based credits are provided during overlapping events. SCE therefore proposed three rules, one for each structure, to address the issue of dual payments as follows:

Structure (1) – The sum of credits provided by the DR energy and capacity programs (e.g. CPP and BIP) is capped at the total value of the generation capacity charges embedded in the customer's OAT. This structure does not eliminate double payment, but rather caps a customer's compensation at no more than they are charged on their rate.

Structure (2) – The credit provided through the energy program is reduced or eliminated when there are concurrent and overlapping capacity and energy program events. The amount of credit provided under the energy program is dependent on the extent to which the events overlap. If the events completely overlap, then no energy credit is provided and the customer only receives the credit associated with the capacity program. If there is a partial event overlap, then the customer receives a prorated credit for the energy program and the full credit for the capacity program. This is consistent with the then-current practice at the time of the filing of SCE's 2009 RDW Application. No changes related to Structure (2) were proposed in that Application.

Structure (3) – The current practice of providing the full capacity program credit with no restriction on benefits offered by the energy program was continued because any modification was deemed to be difficult and costly to implement by the summer 2010. Also, the RTP-2 rate structure requires a re-design soon to align it with a market based structure, and any re-design should account for capacity overpayments at that time.

A numeric example of the capping methodology is provided in the attached testimony.

3b. Can these methods be applied to third-party demand response provider programs such as those participating in the demand response auction mechanism? Explain why or why not.

It is possible to cap incentives for customers dual-participating in the Demand Response Auction Mechanism (DRAM) and an SCE DR energy program, but doing so would require modifications to Rule 24/32 and modifications to SCE's operational processes. For instance, to allow for dual participation between CPP and DRAM, SCE would cap the amount paid through DRAM for CPP dual participating customers to maintain and support the Commission's dual participation policy[5] on not paying twice for the same load drop. This capping is required because SCE cannot know if and when DRAM resources are dispatched, due to stipulations in the DRAM contract, Rule 24/32, and current operational practices. To perform the capping of incentives, new operational steps and pieces of information are needed for SCE to have all of the necessary data to be able to calculate and cap incentives appropriately. These include:

- DRPs with DRAM contracts must provide information to SCE consisting of a comprehensive list of all Service Accounts (SAs) dually enrolled and actively participating in their DRAM resources;
- SCE would then calculate the total value of the generation capacity charges embedded in each SA's OAT to determine the cap ceiling for each;
- SCE would also need the individual DRAM customer payment(s) information from the DRAM DRPs;
- SCE would then calculate, based on the cap ceilings for each SA, the CPP incentives paid and the payment to the DRAM DRP for each CPP customer; and
- These totals would be summed up, and if the sum is larger than the cap, it would result in a capacity payment reduction from SCE to the DRAM DRP, who would then settle accordingly with each customer.

SCE does not recommend allowing dual participation between CPP and DRAM because DRAM is still a Pilot. Moreover, it would be a significant undertaking to implement the processes needed to permit dual participation and to achieve stakeholder support for changes to Rule 24/32. As described in SCE's response to Question 2 above, SCE records show that 18

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[5] *See* D.09-08-027, at p. 154; D.12-04-045, p. 47.

customers in the past 3 years having been dis-enrolled from CPP to participate with a third party aggregator under Rule 24 (i.e. DRAM), out of 40,517 Rule 24 registrations. Permitting dual participation between CPP and DRAM would require complicated policy changes to Rule 24/32, as well as implementation of a potentially complex capping process for Utilities and DRPs. The costs far outweigh the potential benefits.

Further, SCE recommends the current practice of allowing dual participation between CPP and other capacity programs (e.g. BIP) be deemed inappropriate and prohibited. SCE has long maintained that CPP is an event-based capacity program,[6] and continues to do so. CPP's designation as a DR energy program should be changed and reclassified as a DR day-ahead event-based capacity program. Accurately classifying CPP as a capacity program would alleviate other parties' concern that there is currently an uneven playing field for customers choosing to participate in the DRAM capacity Pilot versus an IOU capacity program. In addition, DRAM already contains a form of dual participation that is inherent in its design, as discussed in SCE's response to Question 7 below.

4. (For PG&E and SDG&E only)

N/A

5a. How do you avoid double counting for customers that participate in two programs?

SCE interprets this question as referring to the annual load impact studies for dual enrolled customers. In the ex-post load impact evaluations, the analysis only accounts for actual events and load impacts attributed to customers who participated in each CPP event, controlling for their participation in any other DR events in which they are dually enrolled. In other words, there is only one load change on the event day and to avoid double-counting, both program models account for it.

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[6] SCE Opening Brief submitted in 2009-2011 DR Application (A.08-06-001 et al), p.34 and SCE Opening Comments on the Proposed Decision issued in A.11-03-001 et al, p.18.

For the ex-ante load impact studies, the program-level load impacts are forecasted for all enrolled customers. The portfolio-level load impacts are by definition, adjusted for dual participation. In the ex-ante studies, portfolio-based impacts assume that all programs are called at once. The Commission then takes the values from the annual load impact studies, subtracts out the portion of the programs that cannot be integrated into the CAISO market (SCE refers to these as "crumbs") and grosses up for transmission and distribution losses. The results are used to develop the forecast for the Year Ahead Final Allocations for each IOU.

5b. Explain why this method can or cannot be applied to third-party demand response provider programs?

This method to avoid double-counting cannot be applied to DRAM because DRAM DRPs are not required to perform load impact protocols to receive resource adequacy credit, and it has not been determined if, when, or how they will be in the future. In the past, DRPs participating in Aggregator Managed Portfolio (AMP) contracts[7] with IOUs were required to participate in the load impact process, so there is an established precedent, and most California DRPs are familiar with the process and its purpose. A critical difference between AMP and DRAM, however, is the IOUs' access to customer, dispatch and event performance data for AMP and the Rule 24 competitive neutrality clause[8] that precludes IOU access to DRAM information.

While the Commission evaluates the DRAM pilot to determine whether a permanent DRAM program should be established, the DRAM pilot has been exempted from load impact evaluations through 2019. If dual participation between CPP and DRAM is allowed, future IOU load impact evaluations and protocols will require updates to address this change. SCE recommends that the subject of whether to require DRAM load impact evaluations and their

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7 AMP contracts were bilateral capacity and energy contracts between SCE and third-party aggregators for the procurement of demand response resources. SCE's last AMP contract expired at the end of 2017.

8 *See* SCE Rule 24, C.1.a.(3), available at https://www.sce.com/NR/sc3/tm2/pdf/Rule_24.pdf.

potential impacts to the IOU DR portfolios be addressed through stakeholder workshops. This issue should be settled in advance of any dual participation changes for CPP.

6. What approach would you recommend to allow for the visibility needed by the Utilities regarding what is bid and awarded into the CAISO market while ensuring that customer choices are not decreased? Describe the approach and explain how the approach fulfills both needs. Provide cost estimates for this approach.

SCE supports increased visibility into how DRAM resources are bid and awarded into the market, however, it is unclear whether this visibility can be implemented under the current DRAM contract and Rule 24/32 construct. The Commission will need to evaluate and specifically ensure that any information is only shared in full compliance with all applicable rules and regulations, including any rules aimed at preventing market manipulation.

To improve visibility into bid and dispatch for DRAM resources, SCE recommends the Commission change the DRAM contract and construct to give the IOUs the bidding and dispatch rights in addition to the resource adequacy – similar to RFO agreements. Making this change is allowable under all CAISO and FERC market rules.

SCE does not have a cost estimate at this time, but the capacity payment costs for this type of a contract should be no different than those received in DRAM today. The difference would appear in the form of an incremental energy payment from the Utilities to the DRPs, which should be reflected and supported through market awards of the contract(s).

7. What changes to Rule 24/32 do you recommend to allow dual participation between CPP and a third-party demand response provider program? Justify why these changes are needed. What changes, if any, do you recommend to address the firewall issue described in Section C.1.a.(3) of Rule 24/32? Justify why these changes are needed.

Allowing dual participation between DRAM and CPP would require changes to Rule 24/32, SCE's CISR DRP, and all SCE rate schedules related to CPP, to remove any language that currently restricts dual participation. DRAM contract language would also have to be revised to address the changes to the settlement methodology for DRAM/CPP participants. SCE systems would require changes to allow for this type of dual participation and changes to the firewall rule would also need to be made for the Utilities to verify and calculate the capping. Given the inconsequential number of customers that have been dis-enrolled from CPP to participate with a third party DRP in the past three years (18 customers out of 40,517 Rule 24 registrations), it is not clear that the potentially significant costs to implement these changes for the DRAM, which is still undergoing Commission review as a Pilot, are warranted at this time.

It is worth noting that DRAM is already a form of "dual participation". The idea behind Rule 24/32 participation was to create a mechanism to allow third party demand response providers (DRPs) to participate in the CAISO markets, and bid in the energy from their resources. However, since there is no capacity market in California, and the energy payments are relatively small compared to the total (energy and capacity) resource value – the Commission initiated the DRAM Pilot to provide an opportunity for third party DRPs to collect a capacity payment for their resources. Therefore, the DRAM pilot is already allowing for dual-participation, where the Buyers (IOUs) are providing a capacity payment, and the CAISO market is providing an energy payment to the resource/DRP. The IOUs do not know how the DRPs share these two payment streams with their customers, as this is part of the DRP-to-customer business relationship.

Based on all of the information above and particularly the facts SCE provided to Question 2 above, where SCE identified a total of 18 customers in the last 3 year period who were dis-enrolled from CPP to participate in DRAM, SCE believes the numbers do not support changes that require sweeping policy, program or operational changes for Utilities and DRPs, and their unknown costs to customers. SCE recommends the prohibition of dual participation between an IOU and a third-party DR program should continue. As described in SCE's response to Question 3 above, the proper course of action is to reclassify CPP as a capacity program and end dual participation between CPP and other capacity programs for all customers, regardless of whether their DRP is an IOU or not.

C. Questions on Auto DR Incentive Policy

1. Do you agree with the matrix provided by the Utilities (See Attachment B.) Explain any disagreement.

The SCE portion of the matrix provided in Attachment B excludes SCE's Customized Auto DR Program. SCE recommends the SCE portion of the matrix in Attachment B be modified to include this program in the heading of the third column of the table, alongside Auto DR Express as shown below:

DEMAND RESPONSE PROGRAM/PILOTS	BIFURCATION TYPE	AUTODR EXPRESS & CUSTOMIZED	THERMOSTAT INCENTIVE	SMART ENERGY PROGRAM (PTR) THERMOSTAT INCENTIVE
Base Interruptible Program (BIP)	Supply-Side (RDRR)	No	No	No
Capacity Bidding Program (CBP)	Supply-Side (PDR)	Yes	Yes	No
PG&E Peak Day Pricing (PDP)	Load-Modifying	N/A	N/A	N/A
PG&E SmartAC™	Supply-Side (PDR)	N/A	N/A	N/A
PG&E SmartRate™	Load-Modifying	N/A	N/A	N/A
SDG&E Peak Time Rebate (PTR)	Load-Modifying	N/A	N/A	N/A
SDG&E A/C Summer Saver	Supply-Side (PDR)	N/A	N/A	N/A
SDG&E Critical Peak Pricing (CPP) > 20 kW	Load-Modifying	N/A	N/A	N/A
SDG&E TOU Plus (CPP rate for Res, Small Com, and Agriculture)	Load-Modifying	N/A	N/A	N/A
SCE Agricultural & Pumping Interruptible Program (AP-I)	Supply-Side (RDRR)	No	No	No
SCE Summer Discount Plan Program (SDP)	Supply-Side (RDRR)	No	No	No
SCE CPP (>200kW)	Load-Modifying	Yes	No	No
SCE CPP (<200kW)	Load-Modifying	Yes	Yes	No
SCE CPP (Residential)	Load-Modifying	No	Yes	No
SCE Smart Energy Program (SEP) (also known as PTR)	Supply-Side (RDRR)	No	No	Yes
SCE Real Time Pricing (RTP)	Load-Modifying	Yes	Yes	No
Demand Response Auction Mechanism (DRAM)	Supply-Side (RDRR)	Yes	Yes	No
Demand Response Auction Mechanism (DRAM)	Supply-Side (PDR)	Yes	Yes	No
SDG&E and SCE CBP Residential	Supply-Side (PDR)	No	Yes	No
PG&E Supply-Side (SSP)	N/A	N/A	N/A	N/A
PG&E Excess Supply (XSP)	N/A	N/A	N/A	N/A

DEMAND RESPONSE PROGRAM/PILOTS	BIFURCATION TYPE	AUTODR EXPRESS & CUSTOMIZED	THERMOSTAT INCENTIVE	SMART ENERGY PROGRAM (PTR) THERMOSTAT INCENTIVE
SDG&E Armed Forces	N/A	N/A	N/A	N/A
SDG&E Overgeneration	N/A	N/A	N/A	N/A
SCE Charge Ready	N/A	No	No	No

2. Do you agree with the definition of an Auto Demand Response control, as developed during the workshop? Explain any disagreement.

SCE agrees with the definition of an Auto DR control as "the ability to receive an automated demand response signal to enable the customer to participate in a demand response event for current models of demand response without any manual customer intervention."

3. Explain why you do or do not agree with the following criteria for controls eligible for auto demand response incentives: a) In the case of all three classes of customers (residential, commercial & industrial, and small & medium businesses) the control must be able to receive an Open Auto Demand Response compliant Auto Demand Response signal; b) For commercial and industrial customers, the customer must also be able to provide the anticipated kilowatts expected from the end uses equipped with the control as that is what determines the calculated incentive for that class of customers; and c) In the case of the small & medium business customer class and residential customers receiving incentives for thermostats, the criteria depend upon the type of Auto Demand Response in which the customer is enrolled, deemed incentive based on the average kW load drop for that control in that sector.

In general, SCE supports a policy that requires the ability of an incentivized Auto DR control to receive a signal to automate a customer's DR participation. SCE currently requires OpenADR (Open Automated Demand Response)[9] as a requirement to receive Auto DR Technology Incentives. In order to promote DR to an wider range of customers, including small and medium businesses and residential, SCE recommends that incentives provided for DR controls must be able to respond to a DR signal from a certified and current OpenADR Virtual End Node.

In the case of customized incentives for traditional DR end-uses at commercial and industrial customer sites, SCE currently uses a calculated methodology in its Auto DR

[9] Open Automated Demand Response is a research and standard development effort for the purposes of communicating information and signals for energy management.

applications (called Auto DR Customized). Auto DR Customized applications require customers to provide their estimated kilowatt reduction and dollar costs of the Auto DR measures they plan to install. SCE utilizes a 3rd party engineering company to validate and verify the kW reduction and cost amounts submitted in the customer's Auto DR Customized application are appropriate. SCE agrees with this criterion as stated in the question and recommends it be continued.

In the case of deemed incentives, SCE currently uses a deemed methodology in its AutoDR applications (called AutoDR Express). AutoDR Express applications require customers to identify the measure end use, customer's peak kW demand and customer type/sector to determine the deemed kW amount. SCE utilizes a 3rd party engineering company to verify the kW and amount submitted in the customer's AutoDR Express application is accurate. SCE agrees with this criterion as stated in the question and recommends it be continued.

4. In the case of incentive eligible thermostats, what policy could encourage manufacturers to equip the controls with easy-to-use time-based functions to help a small business or residential customer respond automatically to time of use rates either while they participate in an event-based program that is eligible for Auto Demand Response incentives, after they leave that program, or both?

There are two ways to encourage manufacturers to equip their thermostat controls with time-based functions: (1) increase consumer demand for that functionality or (2) create state policies and/or requirements, such as Codes and Standards, to require the functionality.

5. Should a base interruptible program (a reliability program) customer bidding into the demand response auction mechanism pilot as a Reliability Demand Response Resource be eligible for Auto Demand Response control incentives? (This question is only asked in terms of the pilot and not in terms of whether the pilot becomes a permanent mechanism; that question is premature.)

No, customers who participate solely as reliability demand response resources (emergency only) should not be eligible for Auto DR control incentives, regardless of whether or not they are participating in a pilot or approved program. Customers participating in IOU reliability demand response programs such as BIP have long been ineligible and allowing customers participating in a DRAM reliability demand response resource (RDRR) access to Auto DR incentives creates an uneven playing field. Also, using limited funds for DR resources that will only be used in an emergency, and in some years only for measurement and evaluation events, is not the best use of limited program dollars, consistent with Commission policy.[10] Further, any future long term or indefinite term pilots should not be eligible for incentives if other similar DR programs are not eligible.

6. Should the Cost Causation Principle apply to Auto Demand Response incentives; i.e., if a Community Choice Aggregator or a Direct Access energy service provider offers auto demand response incentives to their customers does this qualify as a "similar" demand response program?

The Cost Causation Competitive Neutrality Principle should not apply to Auto Demand Response incentives at this time. There are many issues and complexities associated with this question, and it would be very difficult to address them fully through this series of questions. Some of these issues include:

- The ability to verify customer performance under the 36-month rule if the customer were participating in a CCA or direct access energy service provider (ESP) program.
- The ability to allocate costs and benefits properly per cost-effectiveness protocols and RA rules if the customer were participating in a CCA or ESP program.
- The ability to recover costs for stranded assets if customers were to move from an IOU to a CCA or ESP prior to completion of their 36-month participation requirement.

The bullet points presented above are generalizations of many detailed issues, operational complexities and policy questions. SCE recommends no decision be made at this time, but rather a body of testimony and information should be created through a series of workshops and discussions on the future of the Auto DR program as it relates to CCAs and ESPs.

7. If a community choice aggregator or direct access provider develops its own critical peak pricing or real time pricing program, should the customers of these programs be eligible for Auto Demand Response incentives if the investor owned utility does not receive the resource adequacy credit for the load modifying demand response benefit? Does the amount the customer pays in distribution charges fairly compensate for the customer's participation? Should there be a carve-out/set-aside or a cap on the Auto Demand Response incentive budget for these customers? How would the Commission determine that carve-out/set-aside or cap?

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[10] *See* D.16-06-029, p. 47: "Given the infrequent dispatch of BIP, we do not consider the Commission's investment in ADR devices recoverable through a reliability program."

See SCE's response to Question 6 regarding SCE's concern with the number of issues and questions to be answered before any final decision is made.

If a CCA or ESP develops its own CPP or RTP program, these should not qualify as qualifying DR programs for IOU Auto DR incentives at this time for the following reasons:

- The IOU would not be able to verify that the customer's controls are receiving a signal from their CCA or ESP (i.e. validate/verify the Auto DR policy);
- The Utility would not be able to verify that the incentivized controls are being used in the customers demand response performance;
- The Utility would not be able to calculate performance calculations, if applicable.

Longer term solutions to the issue could include:

- The IOU moves Auto DR incentive costs to generation rates, limiting eligibility to only bundled customers and IOU-administered qualifying DR programs. This solution would remove the CCA complications and cost causation principle concerns.

Or, if Auto DR costs continue to be recovered through distribution rates, then:

- CCAs meet the 'similar' definition as required by the cost-causation principle and the IOUs cease the collection of program costs. CCAs should be held responsible for reimbursing costs to IOUs where customers have received incentive funding but have not completed their 36-month participation obligation, but it's not clear how the Commission could enforce this reimbursement. In this solution, no mixing of participation between CCA and IOU DR program participation would be allowed.
- The IOU continues to administer Auto DR funding so that all distribution customers fund the costs and remain eligible for Auto DR funding if participating in a qualifying DR program where the Utility receives RA treatment. Alternatively, the CCA or ESP could transfer RA credit to the Utility to account for Auto DR customers under 'similar' CCA or ESP programs to ensure the Utility receives fair value to offset costs.

The principle of weighing costs and benefits appropriately is at the root of the questions above, and it would be improper for the IOU and its customers to pay for costs, such as Auto DR incentives, while the CCA or ESP is exclusively receiving all of the benefits, including carve-outs. It would be improper and contrary to the cost causation principle to implement a policy that causes this mismatch.

8. How often should Auto Demand Response incentives be available to customers; i.e., frequency of incentives? Should the frequency be different for the residential and non-residential programs?

Frequency of incentives should align with the equipment's useful life, which for IOU cost-effectiveness purposes is 10 years. In the case of smart thermostats, the useful life is 11 years.[11]

9. If a third-party provider uses a behavioral approach to encourage a customer to respond, i.e. text or email, should the customer control be eligible for Auto Demand Response incentives?

No, behavioral DR does not align with the AutoDR control policy. See SCE's responses to Questions 2 and 3 above.

10. For demand response resource contracts external to the demand response portfolios and budget applications, should the Commission permit the customers of these contracts to receive auto demand response incentives for the controls? If the Commission determines it should allow these incentives, should such an allowance apply only to future procurements, or should it also apply to past procurements such as those with competitive bids that included all costs? If the Commission does not approve this policy, should the entire contract project site be ineligible for Auto Demand Response incentives including additional capacity in the battery storage or only the procured capacity resource and its controls? If the Commission determines it should permit these contracts to receive incentives, how should the Commission address the future funding issue since the 2018-2022 demand response budget for the incentives has already been authorized? If the Commission were to allow these customers to receive the incentives, should the Commission consider a carve-out/set-aside or a cap on the incentives?

If the demand response resource contracts were awarded based on bids that were purported to represent all-in project costs, then customers of these contracts should not be allowed to receive Auto DR incentives for the controls. If they did receive incentives for these controls, in effect they would be receiving additional money for the same equipment installed as part of their awarded contract, which would result in customers paying twice for the same controls. Allowing customers participating in awarded RFO contracts to also receive Auto DR incentives would lead to lack of visibility in future RFOs such that SCE would not be sure if it is

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[11] *See* Residential Smart Thermostat Workpaper at https://static1.squarespace.com/static/53c96e16e4b003bdba4f4fee/t/57d7624aebbd1a24f2855382/1473733196367/Workpaper+CA+Residential+Smart+Thermostat+Statewide+WorkPaper+Draft+2.pdf

truly procuring the least-cost best-fit resource because it would not know if the counterparty factored in all costs or not. Because both the contract and the Auto DR incentives are a cost to SCE customers, SCE would not be able to verify that it is prudently spending that money to procure DR services.

Auto DR incentives for controls associated with battery storage should be evaluated by the Commission in totality. The current formula for calculating Auto DR incentives for controls, which is based upon the customer's potential kW demand reduction, should be provided on a fixed basis for battery storage end uses (i.e. deemed or flat fee/amount). For instance, a flat fee or amount ("deemed" approach) could be provided for the Demand Response Automation Server (DRAS) client or hardware, plus a fixed or flat amount for labor to install and connect the device to SCE's DRAS and programming the customer's energy management system with the preferred energy management and/or DR strategy.

This would mitigate potential situations where an Auto DR customer includes costs in their Auto DR invoice that are not allowable for Auto DR, such as research and development. This concern is based on SCE's experience to date where battery storage developers have attempted to offset costs associated with the research and development of their native software systems to provide for Open ADR protocols in their Auto DR applications. Currently, SCE is not able to verify that these costs are excluded from the Auto DR incentives paid to a customer, and potential for overpayment exists.

A deemed approach is fair and may limit concerns that a budget overrun for eligible battery storage projects would occur. If guidelines and a formula for a deemed approach were developed soon, IOUs may be able to absorb these extra costs in their current Auto DR budgets for this funding cycle. If not, the new incentive mechanism and funding request could be proposed in the IOUs' mid-cycle applications or a subsequent DR application cycle.

11. Should the Commission require the Utilities to track the incremental load reduction provided by Auto Demand Response technologies and determine whether it fully covers the additional cost of the Auto Demand Response control incentives allocated to demand response programs?

The IOUs currently track the kilowatts incentivized by the Auto DR program. Also, with the current 60/40 payment structure, customers' incentives are adjusted in accordance with the DR provided. It is unclear what benefits will be provided, if any, by tracking incremental load reduction and trying to determine whether it fully covers additional costs.

12. Should the Commission provide additional guidance to the Utilities to create consistency between the calculation of Auto Demand Response incentive amounts applied to each program required for cost-effectiveness and what should that guidance entail? For example, should the Utilities apply incentive costs as capital costs to the ex ante load impacts (SDG&E's method), apply the incentives proportional to admin costs (SCE's method), or based on historical Auto Demand Response expenses (PG&E's method). See Attachment C.

SCE supports consistency in the calculation and application of Auto DR amounts to each DR program that requires a cost-effectiveness calculation. SCE favors its own methodology, but would support a cost-effectiveness workshop with stakeholders in this proceeding, to jointly develop a methodology and calculation for allocating costs when determining DR programs' cost-effectiveness.

13. Should adding or enhancing Open Auto Demand Response capability to battery storage controls for participation in event-based demand response programs as a secondary service be approved as eligible to receive incentives? Is the incremental benefit provided by storage participating in demand response as a secondary service greater than the incremental cost of the incentive?

If the context of this question assumes that battery storage devices are already installed at customer locations and are solely being utilized for retail rate and demand management purposes, and are not included under any current power purchase agreement with a Utility, then incentives for the addition and/or enhancement of OpenADR capability to battery storage controls as a secondary service should be evaluated under SCE's proposal to create a deemed incentive approach for these systems similar to SCE's Auto DR Express program.

If the context of this question is existing storage projects associated with RFO contracts, then SCE sees no incremental benefit to ratepayers of the IOU from providing incentives for this purpose, as the IOU dispatch rights in these contracts overlap and exceed all of the hours that all other DR programs are based upon. Therefore, no incremental DR would be gained by incentivizing battery storage controls associated with existing RFO contracts. Further, there is only one retail meter at each customer location and it is impossible to separate overlapping/coincident dispatch. In addition, IOU customers have already paid for these systems via the RFO contract capacity payments.

14. If the Commission determines that the list of controls eligible to receive Auto Demand Response incentives should include Open Auto Demand Response capability to battery storage controls, what hardware/software costs should the incentives subsidize?

If the Commission determines that battery storage controls should be eligible to receive Auto DR incentives, SCE recommends a fixed incentive amount which covers up to the actual costs of the hardware and installation costs of an incremental OpenADR client/device. If OpenADR capability is already included in the battery storage controls, the fixed amount should be limited to the cost of an equivalent OpenADR device which on average is approximately $5,000.

15. Currently the Auto Demand Response program uses a $200 per kilowatt incentive level and calculates the incentive amount based on a building end use load shed test, with the customer eligible for incentives up to 75 percent of the project cost, if their building performs adequately. Would this be an appropriate incentive design for battery controls and if not, what other design would you propose? (e.g. fixed or flat rate per hardware device, etc.) Based on the exact costs identified above as appropriate, should the Commission adopt a maximum amount for battery storage control incentives, and why? (e.g. should the incentive be bounded by the incremental value the battery storage is providing for demand response above and beyond its primary load management services.)

SCE does not recommend using the Auto DR customized incentive calculation for battery storage controls for reasons stated in its response to Question 13 above.

SCE recommends a fixed incentive amount which covers up to the actual costs of the hardware and installation for an incremental OpenADR client/device. If OpenADR capability is already included in the battery storage controls, the fixed amount should be limited to the cost of an equivalent OpenADR device which is approximately $5,000.

It should be noted that battery storage systems primarily serve to reduce a customer's energy demand, similar to energy efficiency (EE) and distributed generation (DG). Thus, a customer's DR potential may also be reduced by the battery storage system. The current Auto DR program requires a customer to install its EE and/or DG measures first before DR capability is determined, to account for these measures and avoid overpaying for the Auto DR controls. Therefore, if a calculated (i.e. $ per kW) Auto DR incentive for battery energy storage controls is approved by the Commission, incentive eligibility should be postponed until 1 year after installation of the battery system to establish new customer usage data, and incentive calculations should be limited to a customer's summer specific baseline, which is the average on-peak demand from May to October.

16. Given that battery storage is eligible to receive incentives for controls from other publically-funded programs, such as SGIP, what requirements should be in place to enable utilities reviewing incentive applications to prevent incentivizing the same equipment cost a second time?

SCE recommends the following requirements to prevent double-payment (i.e., incentivizing the same equipment twice):

- Applicants must disclose source(s) of other incentives for which they are applying at the time of application. For instance, if an applicant applies for Auto DR, then six months later applies for SGIP incentives, the customer would be required to disclose that information on an updated Auto DR application and/or amended application. Failure to disclose any subsequent relevant incentive applications in a timely manner would result in immediate rejection of one or both applications.

- Program Administrators (PA) of the incentive programs should frequently update and share project and/or reservation lists with each other to ensure that applicants are disclosing incentive applications in a timely manner.

- Incentive programs should be consistent in their requirements for obtaining applications' cost details and information. By requiring consistent cost information, a PA can determine or verify that the same costs are not being sought through multiple funding streams on a single project.

D. Questions on Managing or Modifying the Two Percent Reliability Cap

1. Explain whether the Commission should or should not consider adopting additional flexibility in the trigger by allowing its use anytime within the Warning stage.

Based on CAISO's current Operating Procedure 4420[12] as well as SCE's current reliability program tariffs[13], it appears that CAISO can enable RDRRs in the market anytime within the Warning stage. Therefore, SCE does not oppose the CAISO enabling RDRRs in the market anytime within the Warning stage as currently outlined in Operating Procedure 4420. SCE's current BIP and API tariffs would not need to be amended.

SCE notes an excerpt from the 2010 Reliability-Based Demand Response Settlement Agreement[14] that states, "The RDRP product design will modify the existing trigger from pre-Stage 1 imminent to the point immediately prior to the CAISO need to canvas neighboring balancing authorities and other entities for available exceptional dispatch energy/capacity." SCE further acknowledges that CAISO's current tariff and Operating Procedure 4420 conflict regarding when RDRRs are eligible for dispatch during a Warning, as the tariff is more specific and reflects the settlement agreement language:

- Section 34.7 of the CAISO tariff states: "The CAISO may make Reliability Demand Response Resources eligible for Dispatch in accordance with applicable Operating Procedures either: (a) after issuance of a warning notice **and immediately prior to a need for the CAISO to attempt to obtain assistance from neighboring Balancing Authorities or imports**; (b) during stage 1, stage 2, or stage 3 of a System Emergency; or (c) for a transmission-related System Emergency."
- Section 3.3 of Operating Procedure 4420 states: "The ISO System Operator May take, but is not limited to, the following actions **in any order** needed, and to the extent necessary, to prevent, mitigate or otherwise manage a System Emergency…"

Out of the 20 steps outlined in Operating Procedure 4420's Warning procedure, canvassing other entities and Balancing Authorities for available supply is the very last step.

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12 https://www.caiso.com/Documents/4420.pdf

13 BIP Tariff: https://www.sce.com/NR/sc3/tm2/pdf/CE195-12.pdf, See Special Condition 5.a.; API Tariff: https://www.sce.com/NR/sc3/tm2/pdf/ce71-12.pdf, See Special Condition 3.a.

14 *See* Rulemaking R.07-01-041, Phase 3 as Appendix A to Decision D.10-06-034.

Thus, it appears while the language in Operating Procedure 4420 allows CAISO operators the flexibility to skip steps as needed and currently lists enabling RDRRs at step 14, the CAISO tariff supersedes and negates that flexibility and effectively places the utilization of RDRR resources next to last in the order of a Warning. SCE recommends that the Commission work with the CAISO to determine the proper venue to resolve this issue.

2. Explain whether the Commission should or should not consider adopting additional flexibility in the trigger by allowing its use in other stages prior to the Warning stage, such as Alert notice and/or Restricted Maintenance Operations.

SCE does not support using Restricted Maintenance Operation (RMO) notifications to enable RDRRs in the market due to the frequency and nature of the notifications. There have been 109 RMO notifications since 2008. RMO notifications simply ensure all grid assets are available for use and are not indicative that RDRR(s) will be dispatched.

SCE does not support using Alert Notices to dispatch RDRRs out-of-market. Alert Notices are provided day-ahead and an out-of-market dispatch in this scenario would be appropriate.

SCE does not oppose exploring the idea of using Alert Notices to enable RDRRs in the market. However, SCE does have concerns about how the CAISO would operationalize this process. First, the timing of the Alert Notices (by 3pm the day before) does not align with day-ahead market awards (typically by 1pm). Also, SCE questions whether this would be the correct approach given the effort and cost involved for something that is rarely used (there has only been one Alert Notice since 2008).[15] Various tariffs and systems would need to be updated by SCE and the CAISO. SCE has not yet explored the resulting costs in detail, but given the infrequent use of Alerts, SCE's present assumption is that the costs would outweigh the benefits.

SCE recommends that the Commission work with the CAISO to determine the proper venue to resolve these issues.

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[15] https://www.caiso.com/Documents/Alert_WarningandEmergenciesRecord.pdf.

II.

CONCLUSION

SCE appreciates the Commission's consideration of these matters and appreciates the opportunity to provide these responses.

Respectfully submitted,

ANNA VALDBERG
ROBIN Z. MEIDHOF

/s/ Robin Z. Meidhof

By: Robin Z. Meidhof

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: 626-302-6054
E-mail: robin.meidhof@sce.com

Dated: July 20, 2018

Attachment A

PREPARED TESTIMONY IN SUPPORT OF SCE's

2009 RATE DESIGN WINDOW APPLICATION

Application No.:	A.09-12-___
Exhibit No.:	SCE-1
Witnesses:	R. Thomas

SOUTHERN CALIFORNIA EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

PREPARED TESTIMONY IN SUPPORT OF SCE's 2009 RATE DESIGN WINDOW APPLICATION

Before the

Public Utilities Commission of the State of California

Rosemead, California
December 23, 2009

PREPARED TESTIMONY IN SUPPORT OF RATE DESIGN WINDOW APPLICATION

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I.

INTRODUCTION

Pursuant to the Rate Case Plan (D.07-07-004), Decision Adopting Demand Response Activities and Budgets for 2009-2011 (D.09-08-027), and Decision Adopting Settlements on Marginal Cost, Revenue Allocation, and Rate Design (D.09-08-028), Southern California Edison Company ("SCE") makes the following proposals:

1. Consistent with the guidance provided in D.09-08-027 and D.09-08-028, modify the capacity-related credits provided under SCE's Critical Peak Pricing ("CPP") and other demand response ("DR") programs, such as the Base Interruptible Program ("BIP"), to appropriately limit the total credit provided to customers who participate in more than one program to avoid overpaying customers for their DR participation.

2. Modify the Residential and Small Commercial Rate Design Settlement Agreement approved by D.09-08-028 to defer the increase to Summer Discount Plan ("SDP") credits that would otherwise occur in 2010. This modification is necessary due to the limits imposed by the Commission on SDP program participation in D.09-08-027 and due to anticipated changes to be made to the SDP program in 2011.

SCE's proposals will not result in any changes to SCE's authorized revenue requirements and are designed to maintain the allocation of revenues among rate groups that is reflected in the Revenue Allocation Settlement Agreement approved by D.09-08-028.

II.

PROPOSAL TO ACCOUNT FOR CUSTOMER PARTICIPATION IN MORE THAN ONE DEMAND RESPONSE PROGRAM

A. Background

On June 2, 2008, SCE filed Application (A.) 08-06-001 requesting funding for DR programs for 2009 – 2011.[1] In that proceeding, the Commission considered whether customers could concurrently

[1] SCE's original application was revised on September 19, 2008.

participate in more than one DR program. In D.09-08-027, the Commission characterized CPP as an energy program, allowing customers to enroll in both CPP and a capacity-based program under the following guidelines:

1. Customers shall be allowed to participate concurrently in up to two DR activities, if one provides energy payments and the other provides capacity payments.
2. Customers shall be prohibited from concurrent participation in programs with the same trigger (day-ahead or day-of); however, a participant may participate in one day-ahead and one day-of program.
3. In the case of simultaneous or overlapping events called in two programs, a customer enrolled in those two programs shall receive payment only under the capacity program but not for the simultaneous event under the energy payment program.
4. The CPP program shall be considered to provide an energy payment, not a capacity payment, for the purpose of the dual program participation rules.

In comments on the Administrative Law Judge's (ALJ's) proposed decision in A.08-06-001, SCE and others argued that allowing dual participation on CPP and a capacity-based program (*e.g.*, BIP) would result in duplicate payments for generation capacity and potentially negative generation capacity-related demand charges. These types of overpayments produce DR program combinations which are not cost-effective thus conflicting with the State's Energy Action Plan, which ranks only cost-effective DR as first in the loading order.[2] The Commission acknowledged this possibility in D.09-08-027, and allowed utilities to propose modifications to DR rates to prevent duplicate payments or negative capacity-related demand charges no later than May 1, 2010.[3] SCE proposes modifications in this application pursuant to Ordering Paragraph 7 of D.09-08-028, which states, "If the decision ultimately adopted in A.08-06-001 will require rate design changes to avoid duplicate payments or negative demand charges, SCE shall file a 2009 Rate Design Window Application proposing these changes."

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[2] See page 2 of Energy Action Plan II adopted by the CPUC in October 2005.

[3] D.09-08-027, pp. 155-157.

B. SCE's Proposal

Re-defining CPP as an energy-based incentive program requires SCE to both modify its dual enrollment guidelines and to cap rate credits for certain customers. These caps prevent DR program credits from exceeding the total capacity charges. In SCE's current rate structures, for most time variant rates, all or most of the assigned generation capacity costs are recovered through time-related demand charges. For non-residential non-time variant rates, generation capacity costs are recovered either through seasonal energy or demand charges. As a guiding rate design principle, the credits provided to customers who participate in more than one DR program should not exceed the total value of capacity[4] reflected in the otherwise applicable tariff ("OAT"), regardless of whether the capacity costs are recovered through an energy charge component, a demand charge component, or a combination of the two. To accomplish this, SCE proposes to implement three rate design treatments, which are described below.

Capacity-based DR credit programs offered by SCE generally provide credits to customers based on the value of capacity provided by the customer compared to the cost of capacity provided by a combustion turbine. This method of establishing capacity credits was reflected in the settlement agreements adopted in D.09-08-028.[5]

SCE's DR energy programs, which are called on a day-ahead basis, provide credits to customers through three basic structures:[6]

(1) The first structure provides credits in each summer month regardless of whether a triggering event is called. Rates are designed so that the total value of the monthly credit is offset or balanced by an increased energy charge which only applies to usage during a called event period. The CPP program is one example of this type of structure.

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[4] A value of $114 per kW-yr was adopted in Phase 2 of SCE's 2009 GRC.

[5] SCE-4 (Updated), p.8. This method is consistent with the methods proposed by both SCE and PG&E in the DR Cost-Effectiveness proceeding (R.07-01-041).

[6] The Demand Bidding Program ("DBP") can be called on a day-of or day-ahead basis. SCE is proposing to eliminate the day-of option to allow DBP customer greater flexibility in choosing dual enrollment options. If the day-of option is maintained, customers on DBP would be prohibited from dual participating on any other program as the DBP program trigger is currently called on a day-of and day-ahead basis.

(2) The second structure provides credits on a per event basis applied to the kWh reduction during the event, with no offsetting increased charge. An example of this type of program is DBP. Funding for these types of programs is provided through a generation-related balancing account.

(3) The third structure provides benefits to customers who can avoid usage during certain high-cost hours where generation costs are concentrated. These benefits are essentially embedded in rates and reflected as lower hourly generation charges during the low-cost periods. An example of this type of rate structure is Real Time Pricing (RTP).

SCE proposes three rate design treatments corresponding to these three structures when customers participate in both capacity and energy programs, as shown below.

Table 1

Energy and Capacity Based Programs Dual Enrollment Relationships

	Energy Program	Capacity Program	Treatment Rule
Structure (1)	➢Per event charge ➢Day-ahead trigger ➢Monthly credit **(example: CPP)**	➢Monthly Credit ➢Day-of trigger **(example: BIP)**	Cap summed credits to value of capacity reflected in the otherwise applicable tariff rate
Structure (2)	➢Per event credit ➢Day-ahead trigger **(example: DBP)**	➢Monthly Credit ➢Day-of trigger **(example: BIP)**	Eliminate energy program credit for concurrent events
Structure (3)	➢Embedded credit ➢Day-ahead trigger **(example: RTP-2)**	➢Monthly Credit ➢Day-of trigger **(example: BIP)**	Temporarily continue current practice of allowing dual enrollment without caps

The need for separate treatments is driven by the different energy programs structures. A single capping structure would satisfy the requirements for structure (1) type programs, however it may not comply with Commission guidelines regarding programs that fall under structure (2) where only capacity-based credits are provided during overlapping events.[7] SCE is therefore proposing three rules, one for each structure, to address the issue of dual payments as follows:

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[7] *See* D.09-08-027, p. 156.

- Structure (1) – The sum of credits provided by the DR energy and capacity programs (e.g. CPP and BIP) will be capped at the total value of the generation capacity charges embedded in the customer's OAT.[8]
- Structure 2 – The credit provided through the energy program will be reduced or eliminated when there are concurrent and overlapping capacity and energy program events. The amount of credit provided under the energy program will depend on the extent to which the events overlap. If the events completely overlap, then no energy credit will be provided and the customer will only receive the credit associated with the capacity program. If there is a partial event overlap, then the customer will receive a prorated credit for the energy program and the full credit for the capacity program. This is consistent with current practice. No changes related to structure 2 are proposed in this application.
- Structure 3 – The current practice of providing the full capacity program credit with no restriction on benefits offered by the energy program will be continued as any modification would be difficult to implement by summer 2010. Also, the RTP-2 rate structure will require re-design soon to align it with the MRTU structure, and any re-design should account for any capacity overpayments at that time. SCE will monitor dual participants along with progress on the Proxy Demand Resource market and propose a mechanism to address potential overpayments in the Dynamic Pricing application due to be filed September 1, 2010,[9] rather than in this application.

The relationships outlined above cover the majority of possible dual enrollment scenarios. The combinations of dual enrollment programs are shown in Appendix A.

SCE is not proposing any capping rules for customers who participate in both the Peak Time Rebate ("PTR") program and the Summer Discount Plan ("SDP") at this time. While the potential for

[8] These capacity charges may be reflected in energy ($/kWh) or demand ($/kW) rate components.

[9] Ordering Paragraph 12 of D.09-08-028 requires SCE to make a Dynamic Pricing filing by September 1, 2010.

dual payments certainly exists for this combination of programs, the timeline of Edison's SmartConnect deployment will delay any significant PTR credits until 2011, and time is needed to evaluate the quantification and remediation of any such over-payments.

In general, the capping mechanism associated with Structure 1 would simply cap the sum of participation credits to the value of the time-differentiated generation demand charges present in each customer's OAT. This would continue to be the case for customers served at voltages at or exceeding 2 kV (i.e. primary and sub-transmission voltages). The capping mechanism for customers served at secondary voltages (<2 kV) requires modification due to the mechanism by which SCE recovers capacity-related costs in the rate structure. Under the rate design settlements authorized in D.09-08-028, capacity costs for time variant rates at the Secondary voltage level (less than 2 kV) are recovered partially through demand charges and partially through energy charges, with 83% of the capacity-related costs recovered through the on-peak and mid-peak time-related demand charges and the remainder recovered through on-peak and mid-peak energy charges. In order to apply capping for this structure, SCE will develop total capacity rate factors, on a $/kW or a $/kWh basis, that will reflect the total value of capacity embedded within the OAT.[10] These total capacity rate factors, illustrated in Table A-1 of Appendix A, will define the maximum credit a customer can receive under the capping structure described for Structure 1, thus ensuring customers are not over-compensated for any demand reductions. For consistency, the total capacity rate factor mechanism will be used for all rate groups.

The following example, illustrated in Table 2, describes the steps to determine demand response credits under a Structure 1 scenario. While the example in Table 2 illustrates the benefit calculation for an end use customer served by the utility, this same method will apply to customers dual participating in an aggregator's capacity program[11] and in CPP, with the total benefit and maximum available credit adjusted accordingly. The process starts by first calculating credits provided by each of the DR programs

[10] Absent this modification, simply capping the DR benefits to the total value of the time related demand charges would result in a cap that is less than the overall value of capacity reflected in the OAT for customers served at secondary voltages.

[11] Aggregator programs implemented pursuant to bilateral contracts with SCE would have to expressly allow for dual participation in CPP, in which case this method would apply to such dual participation.

separately. In this case, BIP provides a credit of $25,759 and CPP a credit of $15,413. These credits are then summed to arrive at a subtotal capacity credit value of $41,172 which is then compared to the credit cap to determine the final credit level. As previously stated, the DR credit cap represents the total value of capacity in the OAT. For the TOU-8 secondary customers, the capacity costs embedded in the OAT structure are $35,551. Because the value of the avoided capacity cost (i.e. credit cap) is less than the value of the combined DR benefits, DR credits are reduced by $5,631 to $35,551. In this example, any payment above $35,551 represents non-cost effective DR credits, as SCE would be paying credits in excess of the generation capacity costs otherwise collected from the customer. In this case, SCE would include a negative $5,631 DR adjustment to the customer's final bill.

Table 2 – Example of Structure 1 Credit Cap for Dual Participating on CPP and BIP

Summer Billing Parameters

On Peak Average Demand (kW) =	1,003
Mid Peak Average Demand (kW) =	990
Summer On Peak Demand =	1,236
Summer Mid Peak Demand =	1,222

Incentive Type	**Calculation**	
BIP On-Peak Credit	($19.74) x 1,003 =	($19,801)
BIP Mid-Peak Credit	($6.02) x 990 =	($5,958)
Total BIP Credit		($25,759)
Critical Peak Pricing Credit	($12.47) x 1,236 =	($15,413)
	Subtotal =	($41,172)
Maximum Value of Capacity Credit Available in the OAT		
On-peak	($22.50) x 1,236 =	($27,807)
Mid-Peak	($6.34) x 1,222 =	($7,744)
	Subtotal =	($35,551)
Dual Participation Demand Response Credit		($35,551)

III.

SCE'S PROPOSED TREATMENT OF SDP INCENTIVE LEVELS

SDP provides incentives to participating residential and commercial customers in exchange for them granting SCE the right to cycle their air conditioners when measures to ensure system reliability are required. Capacity-based credits, provided on a $-per-ton-per-day basis, are applied to customer bills in each summer month. As a result of settlement agreements approved by the Decision Adopting Settlements on Marginal Cost, Revenue Allocation, and Rate Design (D.09-08-028) in Phase 2 of SCE's 2009 GRC, these SDP credits would increase by 15% on average beginning in the 2010 summer season. Table B-1 in Appendix B illustrates SDP credit levels in effect during the summer of 2009 and those adopted in Phase 2 of SCE's 2009 GRC.

In this application, SCE proposes to modify the adopted credits and to maintain the SDP credits at the levels that were in effect during the summer of 2009. Retaining the incentives at the levels in effect in 2009 is consistent with the Commission's direction in the Decision Adopting Demand Response Activities and Budgets for 2009-2011 (D.09-08-027). In that decision, SDP participation was capped at August 2009 enrollment and funding levels.[12] The rationale for capping the programs was that an examination of the appropriate size and role of emergency programs was being performed in Phase 3 of R.07-01-041.

As part of the record in Phase 3 of R.07-01-041, SCE has expressed its intent to convert the SDP to a price-responsive DR program, and to transition the currently enrolled residential customers to this new offering.[13] SCE expects to file a plan with the Commission in 2010 that will propose to begin this transition as early as 2011. This new offering, which will include a variable incentive structure that pays customers based on their performance during an event, will be a significant change from the current

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[12] D.09-08-027, OP 11.

[13] R.07-01-041, Pre-Workshop Comments of SCE, October 12, 2009.

incentive structure. In light of this anticipated change to the SDP incentive structure, implementing an increase in SDP credits in 2010 would complicate the transition and could potentially lead to customer dissatisfaction due to inconsistent incentive levels from year to year.

IV.
RECONCILIATION WITH LATEST ADOPTED REVENUE REQUIREMENT AND REVENUE ALLOCATIONS

SCE's proposals will not increase or decrease overall revenue requirements, and rate group revenue allocations adopted in Phase 2 of SCE's 2009 GRC proceeding are maintained per the settlement approved in D.09-08-028. Changes required by the dual enrollment proposals are primarily limited to billing system changes to reflect the new program relationships.

With respect to SCE's SDP incentive level proposal, the inter-class revenue allocation levels reflected in the settlement approved in D.09-08-028 will be maintained by adjusting the SDP credit revenue and surcharge levels by equal and offsetting amounts. In the rate setting process, SCE includes both SDP credits and interruptible program surcharges in rate class revenue requirements for recovery. SDP credits are allocated to rate groups proportionate to customer participation, with 89% of credit revenues applied to the Residential rate group. The current values of SDP credits by rate group are shown in column 6 of Table B-2 in Appendix B. Interruptible program surcharges recover costs for SCE's emergency triggered programs, which include the BIP, SDP, and the API programs. Emergency triggered programs are treated as generation resources, with the associated costs allocated on the basis of marginal generation cost revenues.[14] Returning to the SDP credit levels in effect during the summer of 2009 represents an adjustment (decrease) of $8.2 million. Columns 8 and 9 of Table B-2, demonstrate how the revenue adjustment is applied to SDP credits in proportion to participation (column 8), while the corresponding (equal and offsetting) adjustment to the interruptible surcharge is allocated on the basis of marginal generation cost revenues (column 9). Because of the different distributions of revenues

[14] The interruptible program surcharge is recovered through a Distribution related rate component to allow for Direct Access customer participation in the emergency curtailment programs.

between SDP credits and interruptible surcharges, SCE will apply a rate group level Distribution adjustment (column 10) to ensure the rate group level change in the interruptible surcharge is made in the same proportion as the rate group level change in the SDP credit. By adding this adjustment, SCE will maintain the rate group revenue allocations adopted in Phase 2 of its 2009 GRC Phase 2, as demonstrated by comparing columns 5 and 12.

SCE held conference calls with the majority of GRC Phase 2 settling parties to explain the SDP proposal in this application and to answer any questions the parties may pose.[15] No party to the settlement agreements expressed any objection to SCE making this proposal in this application.

V.

CONCLUSION

SCE seeks approval of rules and rate structures intended to enable the dual enrollment guidelines established by the Commission in D.09-08-027. The dual enrollment structures proposed herein are designed to limit cumulative DR program benefits to avoid uneconomic DR compensation. SCE's proposals comply with Ordering Paragraph ("OP") 30 of D.09-08-027 and OP 7 of D.09-08-028, by defining CPP as an energy program and by following the established dual enrollment guidelines.

SCE also seeks approval to maintain the SDP credit levels at the levels that were in effect during the summer of 2009. The credit level maintenance is justified given the Commission's order to cap funding and participation in emergency triggered programs. Furthermore, this credit level cap supports SCE's efforts to transition the SDP to a price-responsive load control offering. SCE will ensure revenue allocation levels authorized in D.09-08-028 will not be affected by the change.

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[15] Parties who participated in the conference calls include the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), California Large Energy Consumers Association (CLECA), California Manufacturers and Technology Association (CMTA), Federal Executive Agencies (FEA), Energy Producers and Users Coalition (EPUC), and Building Owners and Manager Associations of Greater Los Angeles, Orange County, San Francisco, and California (BOMA).

Appendix A

Table A-1 – Maximum Capacity Credit Available in the Otherwise Applicable Tariff

Rate Group		Maximum Available Credit
Residential		(0.08548) $/kWh
GS-1		(0.08712) $/kWh
GS-2		(23.79) $/kW
GS-2T	On-Peak	(20.86) $/kW
	Mid-peak	(6.37) $/kW
TOU-GS-3	On-Peak	(18.11) $/kW
	Mid-peak	(4.30) $/kW
TOU-8-Sec	On-Peak	(22.50) $/kW
	Mid-peak	(6.34) $/kW
TOU-8-Pri	On-Peak	(22.71) $/kW
	Mid-peak	(6.37) $/kW
TOU-8-Sub	On-Peak	(19.73) $/kW
	Mid-peak	(5.21) $/kW
PA-1		(0.05518) $/kWh
PA-2		(15.68) $/kW
AG-TOU	On-Peak	(12.72) $/kW
	Mid-peak	(3.04) $/kW
TOU-PA-5	On-Peak	(17.13) $/kW
	Mid-peak	(4.81) $/kW

Appendix B

Table B-1 – Comparison of SDP Credits: Summer 2009 vs. 2009 GRC Phase 2 Proposal

SDP Rates Options	Rates Effective Summer 2009 Total Rate	2009 GRC Adopted Rates Total Rate
D-APS		
Air Conditioning Cycling		
Credit - $/ton/summer season day		
50% Cycling	(0.050)	(0.035)
67% Cycling	(0.100)	(0.073)
100% Cycling	(0.180)	(0.358)
D-APS-E		
Air Conditioning Cycling		
Credit - $/ton/summer season day		
50% Cycling	(0.100)	(0.040)
67% Cycling	(0.200)	(0.082)
100% Cycling	(0.360)	(0.409)
GS-APS (Schedules: GS-1 and TOU-GS-1)		
Air Conditioning Cycling Credit - $/ton/summer season day		
30% Cycling	(0.014)	(0.053)
40% Cycling	(0.042)	(0.069)
50% Cycling	(0.070)	(0.091)
100% Cycling	(0.200)	(0.370)
GS-APS (Schedules: GS-2, TOU-GS-3, or TOU-8)		
Air Conditioning Cycling Credit - $/ton/summer season month		
30% Cycling	(0.42)	(1.62)
40% Cycling	(1.25)	(2.11)
50% Cycling	(2.10)	(2.77)
100% Cycling	(6.00)	(11.25)
GS-APS-E (Schedules: GS-1 and TOU-GS-1)		
Air Conditioning Cycling Credit - $/ton/summer season day		
30% Cycling	(0.028)	(0.064)
40% Cycling	(0.084)	(0.084)
50% Cycling	(0.140)	(0.106)
100% Cycling	(0.400)	(0.416)
GS-APS-E (Schedules: GS-2, TOU-GS-3, or TOU-8)		
Air Conditioning Cycling Credit - $/ton/summer season month		
30% Cycling	(0.84)	(1.93)
40% Cycling	(2.50)	(2.55)
50% Cycling	(4.20)	(3.21)
100% Cycling	(12.00)	(12.64)

Table B-2 – SDP Distribution Adjustment

(1) Rate Class	(2) Bundled Sales (MWh)	(3) DA Sales (MWh)	(4) Oct 2009 GRC Avg Rates (¢/kWh)	(5) Oct 2009 Total Dist Revenue ($M)	(6) June 09 AC Cycling ($M)	(7) Oct 2009 GRC AC Cycling ($M)	(8) SDP Cycling Difference ($M)	(9) SDP Cycling Surcharge Allocation ($M)	(10) Dist Adjustment ($M)	(11) Total Adjustment ($M)	(12) Proposed Total Dist Revenue
Residential	28,980	107	15.9	1,534.7	(46.2)	(54.2)	(8.1)	3.0	5.0	8.1	1,534.7
GS-1	4,870	52	17.0	268.0	(0.6)	(0.7)	(0.1)	0.5	(0.4)	0.1	268.0
TC-1	56	2	16.0	4.5	0.0	0.0	0.0	0.0	(0.0)	0.0	4.5
GS-2	14,310	1,048	15.5	677.1	(3.7)	(4.0)	(0.3)	1.5	(1.2)	0.3	677.1
TOU-GS-3	7,611	1,588	13.1	310.4	(1.7)	(1.5)	0.2	0.7	(1.0)	(0.2)	310.4
Total LSMP	26,847	2,690	15.1	1,260.0	(6.1)	(6.2)	(0.2)	2.8	(2.6)	0.2	1,260.0
TOU-8-Sec	8,048	1,921	12.5	235.2	(0.3)	(0.3)	(0.0)	0.9	(0.9)	0.0	235.2
TOU-8-Pri	5,118	1,560	11.5	124.9	(0.4)	(0.3)	0.2	0.6	(0.7)	(0.2)	124.9
TOU-8-Sub	5,287	2,898	8.2	18.7	(0.1)	(0.2)	(0.1)	0.6	(0.5)	0.1	18.7
Special Contracts	463										
Total LP	18,452	6,379	10.9	378.8	(0.7)	(0.7)	0.1	2.0	(2.1)	(0.1)	378.8
PA-1	394	3	18.1	27.9	0.0	0.0	0.0	0.0	(0.0)	0.0	27.9
PA-2	353	11	13.4	12.6	0.0	0.0	0.0	0.0	(0.0)	0.0	12.6
AG-TOU	1,499	62	10.4	42.2	0.0	0.0	0.0	0.1	(0.1)	0.0	42.2
TOU-PA-5	906	3	10.2	19.1	0.0	0.0	0.0	0.1	(0.1)	0.0	19.1
Total Ag.&Pump.	3,153	80	11.6	101.7	0.0	0.0	0.0	0.3	(0.3)	0.0	101.7
Total St.Lights	700	21	19.5	89.7	0.0	0.0	0.0	0.0	(0.0)	0.0	89.7
SYSTEM	**78,131**	**9,276**	**14.3**	**$3,364.9**	**($53.0)**	**($61.2)**	**($8.2)**	**$8.2**	**$0.0**	**$8.2**	**$3,364.9**

Appendix C

Witness Qualifications

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY OF

ROBERT A. THOMAS

Q. Please state your name and business address for the record.

A. My name is Robert Thomas, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am Manager of the Rate Design Group in the Regulatory Operations Division of SCE's Regulatory Policy and Affairs Department. In this position, I am responsible for development of SCE's rate designs. I have held this position since November 20, 2006.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor's of Science and Engineering from the University of Arizona, a Masters in Business Administration from California State Polytechnic University, Pomona and a Professional Engineering License in Mechanical Engineering. Prior to my present position, my responsibilities have included Manager of the Analysis and Program Support Group, within SCE's Business Customer Division, where I was responsible for providing complex customer specific rate and financial analyses involving self-generation, load growth, contract rates, and hourly pricing options. Prior to this position, I was SCE's Program Manager for the Self Generation Incentive Program. In this position, I was responsible for all aspects of the program including dispute resolution, processing applications, program promotion and was SCE's lead representative on the Working Group.

Q. What is your purpose in this proceeding?

A. I am sponsoring the testimony supporting SCE's "2009 Rate Design Window Application."

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.